

STATUS REPORT

**APPLICATION OF IMAGING TECHNIQUES TO OTHER FIELD AND
LABORATORY PROJECTS**

Project BE12, Milestone 1, FY91

by

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Work Performed for the
Department of Energy
Under Cooperative Agreement
DE-FC22-83FE60149

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ABSTRACT

The application of two imaging techniques, petrographic image analysis (PIA) and computerized tomography (CT) to four projects in the Energy Production research division at NIPER is briefly discussed. These applications illustrate the contribution which these state of the art imaging techniques can make to improved understanding of rock properties and oil recovery methods. The following imaging applications were considered:

- 1 Characterization of grain size distributions in reservoir and outcrop facies by PIA (Cooperation with BE1-Reservoir Characterization)
2. Whole core CT density measurements for clay determinations by log analysis. (Cooperation with SGP42)
- 3 CT imaging of surfactant/polymer floods for recovery efficiency studies.(Cooperation with BE4A - Development of Improved Surfactant Flooding Methods)
4. Whole core screening by CT for selection of representative plugs.(Support for industrial client chemical flooding project).

INTRODUCTION

The rock-fluid imaging project in place at NIPER supports reservoir description and advanced oil recovery processes research and development, especially in the areas of reservoir chemistry, physics, and rock-fluid interactions at the micro- and macroscopic scales (pore to whole core scales). This project is aimed at advancing the

understanding of fundamental processes involved in oil recovery by developing, applying and refining cross-cutting imaging techniques and technologies.

The techniques developed in this project are being used to characterize pore to core scale heterogeneities for DOE funded research projects and projects for industrial clients. These techniques are used to provide near-term field RD&D support in the characterization of pore structures and surfaces, and rock/fluid interactions as applied to the evaluation of enhanced oil recovery processes for class I, II, and other reservoirs. A longer-term goal is the application of techniques developed in this project to the study of oil trapping, recovery mechanisms, and scaling-up procedures from core plug to whole core to interwell scales, to newly developing novel enhanced oil recovery processes.

Considerable progress has been made in using the following rock-fluid imaging technology in quantifying the effect of rock heterogeneities on oil recovery:

(1) The development of a computerized image analysis system for rapid and automatic measurements of pores, pore throats, and grain sizes from thin sections of reservoir rock.¹ These petrographic measurements are used to calculate porosity and permeability values. Whole core, sidewall cores, or drill cuttings may be used to determine reservoir permeability and porosity, thus increasing versatility while lowering sampling costs. This technology can provide information needed to solve formation damage and production problems in oil and gas reservoirs.

(2) Computerized tomography (CT) technology, is a powerful tool for nondestructive measurement of variations in rock properties and fluid saturations in reservoir rock.

Research using this technique has been ongoing at NIPER for more than five years using local hospital CT scanners, in the investigation of heterogeneities and fluid flow in cores. NIPER acquired a third generation medical CT scanner in 1989. Software has been developed for image processing and analysis to provide quantitative time-dependent measurements of oil, brine, and gas spatial saturation distributions in cores during flow experiments.² Recently implemented rapid data transfer from the CT to an image processing workstation allows real time image transfer. Large numbers of scans can be performed and processed by state-of-the-art 3-D image processing software, thus taking full advantage of the rapid scan time (20 sec/scan) of the CT scanner. Also the installation of a positioning table with accuracy better than ± 20 microns, allow multiple experiments to be ran simultaneously on the CT scanner, thus increasing instrument efficiency.³ This allows CT imaging to be an integral part of special core analysis contracts, for rapid determination of core heterogeneity, used in the selection of representative core plug samples from whole core.

(3) Nuclear magnetic resonance imaging (NMRI) is another nondestructive imaging technology used to image fluids within core. NIPER is on the forefront of NMR imaging developments in: (A) resolution, (B) image processing, and (C) distinguishing oil and water phases. A commercial high-resolution Fourier Transform NMR spectrometer has been modified to be used as an imaging instrument and has already been used to generate 3-D images of fluids in cores and beadpacks with resolutions as low as 25 microns. A maximum image resolution of 10 microns is anticipated, based on the high field, the small bore of the spectrometer's superconducting magnet, and other instrument characteristics. By comparisons, NMRI instruments used for medical purposes generally have about 500 micron resolution. The high resolution achievable

allows visualization of the effect of rock/fluid interaction on oil, water, and gas distributions within pore spaces of reservoir rocks. Such a capability aids in the understanding oil displacement processes taking place at the pore level and is essential in understanding the mechanisms of various oil recovery processes.

(4) Pore level fluid displacements using micromodels is a new technique that has been developed at NIPER using thin-slab (3 mm) micromodels built from of sandstone samples. Pore-level fluid flow and fluid displacement processes for oil, gas, and water phases have been observed by optical microscopy. This technique, combined with flow experiments performed on cores, can be used to improve the understanding of mechanisms by which various oil recovery processes remove oil from reservoir rock. This technique can help in the design of an optimum recovery process for a given reservoir rock by enabling observations, at the pore level, of the effects of various flow regimes, fluid properties, and injected chemicals on oil mobilization.

Integration of the above rock/fluid imaging techniques for understanding effects of small-scale rock heterogeneities on oil trapping in reservoir rocks for processes taking place at conditions relevant to oil recovery is one of the unique features of the rock fluid imaging project. The integration of these techniques enables a more definitive assessment of the roles of heterogeneities in affecting oil entrapment, fluid flow and fluid saturation distribution. The combination of these methods helps to investigate the effects of various scales of heterogeneities (pore to core scale) on oil recovery efficiency, and to provide a comprehensive understanding of the oil recovery mechanisms.

A discussion of each of these applications follows.

1.Characterization of grain size distributions in reservoir and outcrop facies.by PIA

The objective of the reservoir assesment and characterization project is to develop a methodology for the effective characterization of shoreline barrier reservoirs⁴. As part of the methodology, an important part is played by the geological characterization of rock facies from different shoreline barrier reservoirs and corresponding outcrops. The grain size distribution measurement is a necessary component of rock description. By replacing the traditional manual point count technique with computer assisted PIA techniques a larger number of thin sections could be analized, to generate more representative data.

Grain size and sorting (standard deviation of grain size) were determined from 75 thin sections by petrographic image analysis of 300 points from each thin section. Forty five samples were from cored wells located in Arch Unit of Patrick Draw field situated in southwestern Wyoming. The remainder of samples were from Almond Formation outcrops located on the eastern flank of the Rock Springs Uplift as close as 8 miles west of Patrick Draw Field. A summary of the results follows. The detailed findings are presented in the BE1 topical report.⁵

Grain sizes among combined Almond outcrop and subsurface samples range from coarse silt to fine sand (30-225 microns) and fall into two groups: 1. A finer-grained and better sorted group comprising tidal creek and tidal flat facies with the tidal flat mean grain size being consistently finer than all other facies.and 2. A relatively coarser-grained and poorer sorted group, comprising all of the other facies including tidal delta, tidal channel, and tidal inlet facies. These relationships are generally expected because the tidal channel, tidal inlet, and tidal delta facies were deposited in higher energy settings than were the tidal flat and tidal creek facies.

Tidal channel grain size distributions are similar. for both the outcrop and the subsurface while outcropping tidal delta, tidal creek and tidal inlet samples tend to be coarser grained than their subsurface counterparts.

The cross-plot of mean grain size versus standard deviation of grain size (sorting) shows a linear relationship with a high correlation coefficient ($r=0.95$), for outcrop as well as for subsurface data sets. The general trend of increasing grain size with decreasing sorting (standard deviation of grain size) might be due to the greater availability of a wide range of grain sizes for the coarser samples.

The scatter plots of porosity versus grain size and porosity versus sorting (standard deviation of grain size) show similar but highly overlapping facies distributions but no linear relationship exists between porosity versus either grain size or sorting for neither subsurface nor outcrop samples. Subsurface tidal creek and tidal flat facies consistently tend to have lower porosity, finer grain size, and better sorting than tidal channel and tidal delta samples. Outcropping samples from tidal channel, middle shoreface, and tidal creek facies tend to be slightly less porous, have finer grain size, and better sorting than exhibited by swash bar, tidal delta, tidal inlet, and oyster bed facies.

Also, the scatter plots of permeability versus grain size and permeability versus sorting are very similar, but no linear relationship exists between permeability versus either grain size or sorting for neither subsurface nor outcrop samples, and the data from these scatter plots are clustered into facies dependent groups. Outcrop middle shoreface and tidal channel data tend to be finer grained, better sorted, and slightly less permeable than outcropping tidal delta, tidal swash bar, and oyster bed facies. Subsurface facies grain size and sorting appear to be independent of permeability if the same very low permeability samples are treated as a distinct group, as

discussed for the porosity versus permeability scatter plots above.

Mean grain size for the Almond Formation (a mesotidal shoreline barrier system) lies in the 30-225 microns range, which is similar to the mean grain size for the Muddy Formation (a microtidal shoreline system, previously studied in the BE1 project) which lies in the 95-150 microns. On the other hand the Muddy Formation samples lack grains coarser than 150 microns, the outcrop and subsurface facies have very similar distributions and the marine facies have narrower ranges of sizes.

Although the sorting for both formations is similar, the Almond Formation facies have consistently poorer sorting than the equivalent Muddy Formation facies. Also, both formations show similar good correlations between sorting and mean grain sizes.

The differences in the grain size distributions and sorting between the two formations could be explained by considering the different energies of the processes involved in the various facies in the two formations.

2. Clay determination by log analysis

The presence of clay minerals has a great impact on petrophysical properties, like porosity and permeability of reservoir rocks. Their presence and type can be determined by thin section, XRD, and SEM analysis, performed on core material, but due to the cost, only a limited number of wells are usually cored, while most of the wells drilled in a field are logged. To research and design quantitative approaches in the use of logs in determining the presence of clays in a reservoir, an ongoing project is using both core and log data and mathematical analysis of this data.^{5,6}

Due to the fact that clays influence both the average density of the core as well as its mineralogy, two factors which affect the X-ray attenuation, it is expected that CT

scanning to be a useful tool in characterizing the rock. The characteristics of the clay containing cores were studied by CT scanning, searching for correlations between the average X-ray attenuation (expressed in Houndsfield units, H.U.) and various log responses. A number of well described whole cores (Arch 120, 121, 123) from the Patrick Draw field - Almond formation, WY for which various sets of logs are available were CT scanned at 2 to 3 in. intervals using 8-mm thick X-ray beams. The data consisting of average CT density for each core cross section image were correlated with wireline density sonic, gamma ray, neutron and resistivity logs. Excellent correlations ($R=0.98$) between the sonic density and CT density were observed for relatively homogeneous (uniform clay content) core from Arch 120, and lower correlations for the more heterogeneous cores (Arch 121, 123).

Small scale (smaller than 1 in.) heterogeneities in the core (fractured, cemented, or clay-rich zones) were clearly apparent in the CT density profile. Their effect on the density log response might be very small, though, due to the effect of spatial averaging of the properties of 3 - 4 cubic feet of rock in the logging process.

On the other hand, although the correlation between the CT density profile and the gamma ray log was excellent, the CT density did not resolve the presence of a thin shale layer which caused a gamma ray log response. This is probably due to the small density contrast between the shale and the neighboring sandstone.

Further details on the application of the CT scanning to the identification of clays are discussed in the project reports.^{6,7}

3. CT imaging of surfactant/polymer floods

Chemical flooding is the EOR method which has the highest potential of mobilizing residual crude oil from

many US domestic reservoirs, due to the fact that the chemical formulation of the injected fluids can be varied to suit the specific fluids and minerals for a given reservoir. The goal of NIPER research is to improve the surfactant flooding methods of producing oil over a fairly broad set of conditions.

The use of non-invasive rock -fluid imaging methods such as CT scanning is needed to investigate the actual behaviour of injected fluids within the rock during a flood. To differentiate between oil and brine by X-ray with the CT equipment available at NIPER, contrast agents have to be added to either the oil or the brine. For chemical EOR, brine composition is a very important factor in the design of surfactant formulations. Therefore, the oil was tagged by adding iododecane rather than altering the brine composition. The oil used was from the Hepler field, Crawford Co. Kansas and North Burbank Unit (NBU), Oklahoma. The addition of iododecane to both the Hepler

and NBU oil reduced oil viscosity but did not appear to affect oil recovery for comparable oil recovery tests. Their viscosity and gravity were 76 cP and 26.1 API for Hepler oil and 3 cP and 39.5 API for NBU oil, respectively. The general procedures and CT equipment at NIPER have been described previously.^{2,3}

For this preliminary study, in the application of CT to monitor chemical corefloods, two tests, similar to two corefloods performed earlier in the year, were conducted. These tests were selected because oil recovery efficiency was significantly different for the two floods when using the same chemical system. The surfactant formulation for all these corefloods was 0.4% total surfactant concentration in an alkaline brine formulation (1.0% NaCl, 0.95N NaHCO₃, and Na₂CO₃). Surfactant injection was followed by injection of a mobility control polymer. Coreflood information is summarized in table 1.

TABLE 1. - Coreflood results for good and moderate oil recovery tests using the same chemical oil recovery system

Core ID	k, mD	Oil type	Biopolymer, ppm	S _{orsf} ¹ , %	S _{orw} ² , %
CT MONITORED COREFLOODS					
1	561	Hepler	3,500	6.7	81.2
2	150	NBU	1,200	26.7	39.3
COMPARATIVE COREFLOODS					
ASP-1	855	Hepler	3,500	5.0	85.6
ASP-2	220	NBU	1,000	29.2	35.8

1) Oil saturation after waterflood, prior to chemical flood

2) Recovery Efficiency=Oil produced by chemical flood/Oil present before chemical flood

The epoxy-encased Berea sandstone core plugs were scanned dry, after brine saturation, after oil saturation, after the waterflood, after the chemical flood, and after the polymer flood. CT images showed that the oil saturation

differences between the two floods could be observed, suggesting that this technique is a useful tool for identifying and evaluating variables that affect oil recovery efficiency of chemical floods.

For test 1 with high oil recovery, the formation of an oil bank ahead of the surfactant slug could be observed. For test 2, no oil bank was detected, and a Significant amount of oil was bypassed by the aqueous fluids. Core permeability and pore structure as well as surfactant-oil interaction may contribute to the observed differences in oil recovery efficiency. To understand the effect of the rock on the oil recovery, information regarding the minerals present the grain size, pore and pore throat size distributions needs to be generated by using PIA techniques on thin sections and mercury injection and XRD analysis on selected rock samples.

Details of the experiments and images of the oil distribution after the floods are presented in the BE4A topical report.⁷

Additional coreflood experiments are planned using CT imaging to help interpret chemical EOR Methods. Differences in surfactant formulations, mobility control agents, and core properties will be examined to determine their effects on oil recovery efficiency.

4. Whole core screening by CT for selection of representative plugs

An important application of CT scanning is in nondestructive evaluation of whole cores for selection of locations where representative core plugs should be taken. The X-ray attenuations visible in the CT image are controlled by the porosity and the mineralogy of the rock. With proper calibration, the porosity, minerals and fractures distributions in the core can be determined by the CT and decisions be made about the most suitable locations to take core plugs.

The CT scanning was used to screen 30 ft of core for selection of core plug samples for chemical flooding and to understand the low recovery measured in the floods performed on some of the selected core plugs. Because of

the proprietary nature of the work, no reference will be made to the formation or the location of the field from which the cores were obtained, but some conclusions of the work are as follows:

1. The CT scans allowed selection of core plugs representative of the core provided, by identifying highly fractured zones and the extent of the fractures.
2. The CT scans of a core plug which exhibited a low recovery during chemical flooding identified the presence of a fracture along the plug length. This fracture, visible to the naked eye only at one end of the plug, actually extended significantly into the core along the core length and served as a channel for the fluids during the flood.

CONCLUSIONS

1. Computer assisted PIA provided fast and accurate grain size data needed in understanding similarities and differences between facies deposited in two different shoreline barrier systems.
2. CT determined X-ray attenuations in clay containing cores correlate very well with densities determined by wireline logs. The CT also allows the detection of small (millimeter scale) heterogeneities which are averaged out by the density log
3. CT monitoring of front movement in surfactant /polymer floods provides information regarding the interaction of the chemical system with the oil present in the rock and the location of the bypassed oil.
4. CT screening of whole core provided the information necessary for the selection of representative core plugs. CT scanning can provide direct information regarding the presence of fractures in the core plugs.

ACKNOWLEDGMENTS

The author would like to express appreciation to NIPER staff members, Troy French, Bonnie Gall, Rick Schatzinger and Bijon Sharma for their part in the work that was accomplished in milestone 1 of project BE12 and to Mike Madden from NIPER and Bob Lemmon from DOE for valuable input.

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